BODANZA

KEYSPAN ENERGY DELIVERY NEW ENGLAND

Direct Testimony of Joseph F. Bodanza

Exhibit KEDNE/JFB-1

D.T.E. 03-40

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Joseph F. Bodanza. My business address is One MetroTech Center, Brooklyn, New York 11201-3851.

Q. By whom are you employed and in what capacity?

A. I am the Senior Vice President of Regulatory Affairs and Chief Accounting Officer for KeySpan Corporation. I am also the Chief Financial Officer of KeySpan Energy Delivery New England ("KEDNE"), which is composed of the New England gas distribution companies operated by KeySpan Corporation, including Boston Gas Company d/b/a KeySpan Energy Delivery New England ("Boston Gas" or the "Company").

Q. Please briefly describe your educational background and your business experience.

A. I graduated from Nichols College in 1969. In 1975, I received a Master of Business Administration from Suffolk University, and in 1981, I received a Master of Finance from Bentley College. I joined Boston Gas in 1972 and have held various positions in the financial and regulatory area before becoming Treasurer in 1984. In 1988, I also became Vice President Finance, and a director of the Company. In 1993, I was named Senior Vice President Finance, MIS and Treasurer. In 2000, I became Senior Vice President Finance, Accounting and Regulatory Affairs for KEDNE. In 2001, I was named Chief Financial Officer and Senior Vice President Regulatory Affairs for KEDNE. In addition, as of April 2003, I am Chief Accounting Officer for KeySpan Corporation.

Q. Are you a member of any professional organizations?

A. Yes. I am a member of the American Gas Association, the Northeast Gas Association, the Financial Executives Institute and the Treasurer's Club.

Q. Have you previously testified before the Department of Telecommunications and Energy or any other regulatory agency?

A. Yes. I have testified in several cases before the Department of Telecommunications and Energy (the "Department"), including prior base-rate cases such as <u>Boston Gas Company</u>, D.P.U. 93-60 (1993) ("D.P.U. 93-60") and <u>Boston Gas Company</u>, D.P.U. 96-50 (Phase I) (1996) ("D.P.U. 96-50"). I also testified before the Department in the merger proceedings involving Eastern Enterprises, Colonial Gas Company and Essex Gas Company.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is the following: (1) to provide an overview of the Company's filing; (2) to discuss the changes in the Company's corporate structure that have occurred since the last rate proceeding in D.P.U. 96-50; (3) to outline the Company's proposed performance-based rate plan (the "PBR Plan"); and (4) to discuss other major aspects of the Company's filing, including proposals to establish a reconciliation mechanism for pension and post-retirement employee benefits other than pensions, a weather-normalization clause, a modification to the non-firm margin-sharing structure established in <u>Interruptible Transportation,</u>

D.P.U. 93-141-A (1996), and a mechanism to fund continuing research and development by the natural gas industry. Each of these proposals is discussed in detail in my testimony and in related testimony, as indicated below.

II. OVERVIEW OF FILING

Q. What is the Company requesting in this proceeding?

A. In this proceeding, the Company is seeking to implement a PBR Plan that would establish cast-off rates designed to recover an annual revenue deficiency of $61,304,367, which represents a 9.59 percent increase in the total bill for the average customer. Although it is difficult at any time to raise rates for customers, today's economic environment poses unique challenges for both the Company and its customers. KeySpan recognizes that, in these challenging times, it is critical to maintain an emphasis on cost containment, customer service, system reliability and safety in providing service to customers. Therefore, although the Company's filing allocates the increase across all customer classes in accordance with Department practice, the Company will limit the impact of this base-rate increase on the average customer in each rate class to no more than a 10 percent increase as compared to the customer's 2002 total bill.

Q. Are there other aspects of the PBR Plan for which the Company is seeking approval by the Department?

A. Yes. The Department last established a PBR plan for the Company in D.P.U. 96-50. The seven-year time span between this filing and the Company's 1996 filing is significant in that, historically, the Company sought base-rate relief every two to three years on average. The relatively prolonged period between the 1996 base-rate increase and this filing has been enabled by two factors: (1) the implementation of a PBR plan in 1996 that, over the five-year term of the plan, provided the Company with a measure of additional revenue in consideration of inflationary cost increases; and (2) the Company's success in implementing cost-containment and revenue-enhancement initiatives, which mitigated the impact of inflationary cost increases and system-reliability capital investments not fully addressed by the PBR Plan. Still, the Company's business remains rooted in the installation and replacement of gas distribution mains and services, which is heavily dependent upon labor and capital investment and relatively independent of technological advances experienced in other industries. In this case, the Company is seeking to initiate a new PBR Plan, including cast-off distribution rates, that would enable the Company to meet its obligation to provide safe and reliable service to customers, while also providing the opportunity to maintain pace with inflation and minimize the need for additional base-rate relief over time.

Q. Would you provide an overview of the PBR Plan proposed by the Company in this proceeding?

A. Yes. The Company is proposing a PBR Plan in this case that is substantially similar to the plan approved by the Department in D.P.U. 96-50. The specifics of the PBR Plan are discussed in my testimony below, with the components of the price-cap formula and productivity study set forth in the testimony of Dr.

Lawrence R. Kaufmann. The term of the PBR Plan would commence on November 1, 2003, when the cast-off rates resulting from this proceeding go into effect, and would continue for a five-year period with annual compliance filings establishing rates to take effect on November 1 of each year beginning in 2004, and ending with the last rate adjustment on November 1, 2008. The Company is also proposing that the PBR Plan be extended beyond the five-year term without further action by the Department, unless an investigation by the Department is initiated on its own motion, or at the request of the Company under G.L. c. 164, § 94, or the Attorney General or other entitled persons under G.L. c. 164, § 93.

Q. Would you review the testimony that the Company is providing in this proceeding?

A. In this proceeding, the Company's case is set forth in the testimony of eight witnesses. As I stated above, my testimony covers a number of issues, including the changes in corporate structure occurring since D.P.U. 96-50, the details of the Company's proposed PBR Plan and a discussion of other major aspects of this filing. The calculation of the revenue requirement and resulting revenue deficiency is set forth in the testimony of Patrick J. McClellan, Director of Rate Recovery for KeySpan Corporate Services LLC (the "Service Company"). The testimony of Justin C. Orlando, Vice President of Human Resources for the Service Company, reviews known and measurable changes in payroll and benefit costs and evaluates the reasonableness of the Company's total compensation. The testimony of Dr. Lawrence R. Kaufmann reviews the Company's proposed formula for the price-cap component of the PBR Plan and presents a comprehensive productivity analysis to support the price-cap formula. The testimony of Paul Moul presents the Company's cost of equity analysis. The testimony of Ann E. Leary, Manager of Rates for KEDNE, discusses the Company's post-test year revenue and gas-cost adjustments and presents the allocated cost of service study. The results of the Company's marginal cost study and the proposed rate-design approach are outlined in the testimony of A. Leo Silvestrini, Director of Rates and Regulatory Affairs for KEDNE. Mr. Silvestrini also discusses the Company's proposed Weather Normalization Clause. Lastly, the testimony of Ronald B. Edelstein discusses the Company's proposal on research and development funding.

III. CORPORATE STRUCTURE AND BUSINESS OPERATIONS

Q. Would you please review the operating changes that have taken place since 1996 that have a bearing on the Company's filing in this proceeding?

A. There are several significant changes in the Company's corporate structure and business operations that have occurred since the Company's last base-rate proceeding in D.P.U. 96-50. First, in 1998-99, the Department reviewed and approved the acquisitions of Essex County Gas Company and Colonial Gas Company by Eastern Enterprises, which was the parent company of Boston Gas. In both cases, the Department approved 10-year rate freezes for the customers of the acquired companies and allowed Eastern Enterprises the opportunity to recover its merger-related costs through the retention of operations and maintenance expense savings achieved by consolidating operating and management functions. Following the mergers, activities such as general corporate administration, financial, legal, gas-supply planning, rates and regulatory affairs were consolidated into the Boston Gas operation. In addition, the Company integrated the various information-technology systems of the companies. Pursuant to the Department's directives in those cases, Boston Gas allocates only incremental costs to Colonial and Essex. Incremental costs are those that would not be incurred by Boston Gas but for the need to support the Colonial and/or Essex operations. Eastern/Essex Acquisition, D.T.E. 98-27-A, at 3-5 (1998); Colonial/Eastern Acquisition, D.T.E. 98-128, at 88-89 (1999).

In November 2000, Eastern Enterprises was acquired by KeySpan Corporation, a public-utility holding company with headquarters in Brooklyn, New York. KeySpan Corporation was formed in 1998 as a result of the merger of two natural gas local distribution companies ("LDC"), The Brooklyn Union Gas Company, serving 1,162,000 million customers in the New York metropolitan area, and the Long Island Lighting Company, serving 506,000 gas customers on Long Island. Having added EnergyNorth Natural Gas, Inc., an LDC serving 77,000 customers in New Hampshire through its merger with Eastern Enterprises, KeySpan's core business is the operation of four LDCs in New England and two LDCs in New York, which collectively distribute natural gas to approximately 2.5 million customers. KeySpan also operates an electric distribution system serving over 1 million customers on behalf of the Long Island Power Authority and has other subsidiaries involved in electric generation, gas and oil exploration and production, gas storage, wholesale and retail gas and electric marketing, appliance-repair services, and a number of other energy-related businesses. As discussed in more detail below, KeySpan's status as a registered public utility holding company has led to changes in the way services are provided to KeySpan's operating affiliates, including Boston Gas. In addition, KeySpan's involvement in the Company's operations has had a positive impact on the Company's ability to provide safe, reliable and cost-effective service to customers.

Q. What has KeySpan's entrance into Massachusetts brought to the Boston Gas operations?

A. Like Eastern Enterprises, KeySpan is responsible for the operation of an extensive and aging distribution infrastructure serving a wide-range of customer needs in heavily populated urban and suburban areas in the Northeast region of the United States. As a result, KeySpan brings with it experience and familiarity with distribution operations similar to Boston Gas, while at the same time viewing the operation with a broader focus and having access to the resources and expertise of a relatively larger company. In addition, KeySpan has demonstrated a strong commitment to local operations and community affairs in Massachusetts.

KeySpan's entrance into the New England market has proven to be a benefit for Boston Gas and its customers in the following ways:

- **System Expansion.** KeySpan's central objective in acquiring the Eastern Enterprises operations was to pursue aggressively the substantial growth opportunities available in the New England area due to the relatively low saturation rates for gas service. KeySpan's expansion of the customer base will benefit all customers in terms of increasing revenues and spreading fixed costs across a larger customer base. In 1996, Boston Gas served approximately 547,000 customers and invested $15 million in mains and services to expand the Boston Gas distribution system. In 2002, the Company served approximately 573,000 customers and invested approximately $40 million in mains and services for system expansion.

- **System Reinforcement.** In addition to its substantial investments in system expansion, KeySpan has stepped up its investment in system replacement, increasing annual investment for system reliability from approximately $32 million in 1996 to $54 million in 2002. This increased investment had a profound impact on the system's reliability under the harsh weather conditions experienced in 2002/03. For example, prior to the 2000/01 heating season, the Company identified approximately 1,500 streets (50,000 customers) in the Boston Gas service area where distribution pressures were predicted to be below acceptable levels on a design day. Since 2000, the Company has targeted these low-pressure areas and devoted substantial resources to install system upgrades. By the start of the 2002/03 heating season, the number of points on the system with predicted distribution pressures below design day levels was reduced to zero. These reliability investments were put to the test this past winter as a result of a cold-weather stretch that was unrivaled in the past 30 years, and in fact, represented a design year for the Company. During this winter period, the Company experienced only two pressure-related outages affecting four customers. The Company attributes this performance directly to the significant effort and investment devoted to increase distribution pressures to design day levels across the system.

- **Best Practices.** With involvement in six LDC operations, electric distribution responsibility for 1 million customers and investment in other energy-related fields, KeySpan is uniquely situated to improve the safety, reliability, and quality of service through the adoption of "best practices" among its operating affiliates. Some examples of best-practice changes in the Boston Gas service area are (1) implementation of the "Second Shift" pilot program for the field operations group, which is designed to improve productivity and control overtime through direct supervision of field operations after normal business hours; and (2) establishment of a Field Operations Transportation Committee comprised of management and union personnel to ensure that vehicles, digging equipment, compressors and similar equipment best suited to complete specific operations are delivered to the field where needed.

- **Customer Service Commitment.** KeySpan has a strong commitment to its customers. KeySpan recognizes that the changes proposed in this filing are coming at difficult time given the economic environment. Therefore, the Company will limit the impact of any base-rate increase approved by the Department to no more than 10 percent for the average customer in each rate class as compared to the customer's 2002 total bill. In addition, KeySpan recognizes the value of other customer-support activities such as seeking out and supporting economic development opportunities, offering low-income rate discounts and budgeting assistance, and energy efficiency programs.

- **Customer-Service Initiatives.** In addition to supporting existing customer service programs offered by Boston Gas, KeySpan is pursuing a number of initiatives aimed at helping customers manage their energy bills and at reducing the cost of service for all customers. Among these initiatives is the implementation of the Customer-Related Information System ("CRIS") system in July 2002, which provides the Company with greater flexibility and opportunity to provide helpful account-management services to customers, among other enhancements. With the implementation of CRIS, Boston Gas customers receive the following services:

  Improved Balanced Billing: CRIS increased the flexibility of the Company's balanced-billing program by allowing customers to start a balanced-billing plan at any time during the year rather than once a year. Payment levels are adjusted more frequently to help minimize the settlement payment due from the customer at the end of the payment-plan period.

  Real-Time Billing Updates: CRIS enables the Company to update billing information on a real-time basis, such as for the calculation of cancel and re-bill amounts. Customer service representatives are able to issue final or special-purpose bills on an expedited basis when needed.

Account Management Through the Internet: Customers may pay their bills through the website and take advantage of account-management services, such as arranging for payment plans, enrolling in a budget-billing plan or entering meter reads. Customers are able to access an actual copy of their bill on the Company's website. Therefore, a customer and a Company customer representative can discuss a billing question while both view the actual bill online.

Workload Management: CRIS provides an automated system to queue and distribute work assignments relating to customer bills that are generated by the system and flagged by the system for further review. This enables the Company to be more efficient in managing its billing workload throughout the year and to resolve potential billing issues in a timely manner before the bill is mailed to the customer.

In this filing, the Company is proposing to initiate a Weather Normalization Clause that would stabilize customer bill impacts in colder-than-normal weather periods when customers often experience a "double hit" as consumption levels and commodity prices rise in tandem. The Company is also proposing to continue funding of targeted research and development ("R&D") programs in the natural gas distribution industry. In the past, R&D programs have provided significant value in terms of lowering the cost of distribution-system activities and increasing safety and reliability.

- **Low-Income Assistance Initiatives.** In addition to the discount rate offered to both heating and non-heating low-income customers who are receiving fuel assistance or public assistance, the Company runs a program to provide low-income customers with up to $4,500 in assistance to enable the installation of energy efficiency measures that reduce the customer's consumption. In this filing, the Company is also proposing to initiate the On Track program, which is discussed in more detail below.

- **Community Involvement.** Involvement in the local communities served by KeySpan is a key component of its business philosophy. Since acquiring the Eastern Enterprises operations, KeySpan has renewed the Company's participation in local community activities. Some examples of the Company's initiatives include: participation in United Way's "Keeping Kids on Track" public awareness campaign in collaboration with WCVB-TV; substantial funding of programs offered by the Boys & Girls Clubs of Boston; sponsorship of a City Year Team; and grants to multiple community agencies and programs such as Reaching Out to Chelsea Adolescents (Chelsea), D.A.R.E. (Quincy), Second Step (Newton), Westie (West Roxury High School), Milton High School, Friends of Robbin Farm Park (Arlington), and Fields Corner Main Street economic redevelopment projects (Dorchester).

Q. Would you please describe the On Track program for low-income customers mentioned above?

A. Yes. The On Track program is one that is currently offered by KeySpan to low-income customers in its New York service territory. The program is designed to motivate and train participants in strategies to change their energy consumption and bill-payment patterns. The On Track program achieves this objective through education, counseling and advocacy, which enable low-income customers with a history of payment problems to better manage their finances. The primary components of the program are: (1) individualized customer services; (2) a financial and energy management home-study course; and (3) arrears forgiveness.

In order to qualify for the program, the customer must be a residential heating customer with a gross income of 250 percent or less of the federal poverty level; not eligible for any public assistance that would cover utility arrears, and have a history of payment problems with the Company.

Participants in the program are first provided a financial analysis and the development of an affordable payment plan to address arrears and future bills. A customer representative is assigned to call the participating customer once a month to thank the customer for their payment or to review the reasons for non-payment. If necessary, the customer representative will review the educational and financial material previously provided. Customers with the most difficulty managing payments, or who have special needs, are referred to the Company's in-house social worker. The social worker provides counseling and assistance with money-management skills and helps to access resources such as public benefits, reverse mortgages, kinship foster-care payments, or other resources available to participants. In addition, the Company would coordinate the On Track program services with its energy-efficiency programs.

The arrears forgiveness aspect of the program is critical to the success of the program. The feedback received from participants upon completion of the program has disclosed that the prospect of arrears forgiveness is the prime motivator for participation. If a customer successfully completes the program and fulfills the financial agreement with the Company, the customer is granted forgiveness of account arrears up to $400. The customer receives this benefit through four $100 credits on his or her gas bill over the course of the program as an ongoing incentive.

KeySpan's experience in New York indicates that the program is effective for both the company and the participating customers. Testing of the participants showed that they increased their understanding of financial management concepts, which led to improved money management and bill payment. Also, a review of bill payment performance showed that participants paid about $190 a year more toward their energy bills than they had in the past. In addition, the Company experienced fewer customer termination actions and contacts concerning non-payment.

Q. **Does the fact that KeySpan is a registered public utility holding company have significance for the Boston Gas operations?**

A. Yes. As I stated above, KeySpan Corporation became a registered public-utility holding company under the Public Utility Holding Company Act of 1935 ("PUHCA") as a result of its merger with Eastern Enterprises. As a registered public utility holding company, KeySpan is subject to comprehensive regulation by the Securities and Exchange Commission (the "SEC"). PUHCA grants the SEC authority to regulate a number of holding company activities, including the issuance of securities, the acquisition of utility assets, various inter-company transactions, record-keeping and accounts, and contracts between operating and service companies. Registered holding companies must file numerous routine and transaction-specific reports with the SEC, some of which must be certified by independent public accountants.

Q. What affect does this status have on the operations of Boston Gas?

A. The most significant effect on the Company's operations relating to KeySpan's status as a registered holding company under PUHCA is that any sharing of services between a utility and its affiliates must be carried out within a centralized service company or companies. This structure facilitates the identification of costs and the fair and appropriate assignment of costs to the operating affiliates that are supported by the service company. Therefore, pursuant to SEC requirements, all corporate, administrative, and management functions, including the common services provided by Boston Gas to Colonial and Essex, were transferred to the separately organized Service Company.

Q. Would you please provide an overview of the ways in which the SEC supervises the activities of the Service Company?

A. PUHCA provides the SEC with the authority to implement a comprehensive regulatory scheme to supervise the activities of the Service Company. In particular, the SEC has the responsibility to ensure that the Service Company is organized and operated in a manner that provides a reasonable assurance of efficient and economic performance of services for the benefit of its affiliates, such as Boston Gas. Through its supervision of the Service Company's activities, the SEC ensures that costs are fairly and equitably assigned to the entities supported by the Service Company.

For example, the Service Company is required to directly assign or allocate by activity, project, program, work order, or other appropriate basis, the costs associated with services it provides to each affiliate. The costs of the services are accumulated in designated accounts and are assigned on a direct or cost-causation basis, if possible, or allocated to the appropriate affiliate in accordance with the guidelines set forth in service agreements established between each affiliate and the Service Company. Each of the Service Company's accounting and cost-allocation methods and procedures have been structured so as to comply with the SEC's standards for service companies operating within a registered holding-company system. In addition, the Service Company uses the Uniform System of Accounts for Mutual Service Companies established by the SEC for holding company systems. SEC rules further require that KeySpan charge Boston Gas for services rendered by the Service Company at cost and that annual reports to account for the services and costs charged to each affiliate be made to the SEC.

KeySpan cannot change the organization of the Service Company, the type and character of the affiliates that will receive its services, the methods of cost allocation, or the scope or character of the services rendered, unless written notice is provided to the SEC allowing an opportunity for investigation and approval of those changes.

Q. **What are the specific services provided to Boston Gas by the Service Company, and how has the service-company arrangement changed the structure of the Boston Gas operations?**

A. As stated above, SEC regulations require that all corporate and administrative services provided on a shared basis to multiple affiliates be moved into a separate entity so that costs may be fairly and appropriately assigned to the affiliates for which service is provided. The shift to a shared-services structure for the New England LDCs, including Boston Gas, occurred in two phases. The first phase occurred on January 1, 2001, when corporate officers and information-technology areas were integrated into the Service Company. As of January 1, 2002, all other shared services were consolidated into the Service Company, which includes finance, regulatory, gas-supply planning, human resources, sales and marketing, purchasing and various other functions. At present, there are approximately 634 Service Company employees located in Massachusetts who are performing corporate, administrative or management services for KeySpan's New England LDCs on a shared basis. On an overall basis, however, the Boston Gas organization remains largely the same. The essential difference is that employees who would have performed shared services for the New England gas distribution operations as Boston Gas employees are now employees of the Service Company. This means that the costs associated with these employees are incurred by the

Service Company and assigned to the operating affiliates supported by the Service Company.

In addition to employee costs, all other costs incurred by KeySpan on a shared basis for the New England LDCs are charged to the Service Company and then assigned to the operating affiliates pursuant to SEC requirements. These costs include the expense and investment associated with shared information-technology systems, such as CRIS and other customer and work-management systems. Under the shared services arrangement, Boston Gas is billed each month by the Service Company for its share of the costs incurred by the Service Company to support the operations of the Massachusetts LDCs. In this case, the Service Company charges to Boston Gas are incorporated in the Company's cost of service, as presented in the testimony of Mr. McClellan.

A full description of the services provided by the Service Company and the methods for cost assignment and allocation to its affiliates, including Boston Gas, are set forth in a written service agreement. The structure and staffing of the Service Company, and the policies and procedures that the Service Company will use to implement the service agreement, have been reviewed and accepted and/or modified by the SEC. This agreement is on file with the SEC and is provided in this filing as Exhibit KEDNE/PJM-3, which accompanies the testimony of Mr. McClellan.

Q. Aside from facilitating the fair and appropriate assignment of costs, are there any other benefits for Boston Gas under the Service Company arrangement?

A. Yes. In addition to meeting SEC requirements, the formation of a service company framework creates efficiencies of scale and scope that ultimately help to reduce the cost of service for all operating affiliates supported by the Service Company. By establishing a centralized entity to provide services to designated operating affiliates, KeySpan is able to implement common corporate policies, streamlined business processes, purchasing advantages and integrated information systems, which greatly enhance the cost-effectiveness of the services provided to each affiliate. In fact, the service-company framework is ideal in terms of giving effect to the Department's merger policies that seek to minimize the cost of service to customers through the elimination of redundant functions, the consolidation and integration of common systems and the transparent assignment of cost responsibility to participating operating companies.

IV. PERFORMANCE-BASED RATE PLAN

Q. What is the Company proposing for a PBR Plan in this proceeding?

A. As I stated above, the Company is proposing a PBR Plan in this case that is structured to be substantially similar to the plan approved by the Department in D.P.U. 96-50. Under the Company's proposed PBR Plan, the Department would first establish cast-off distribution rates based on cost-of-service ratemaking principles. Second, the base rates that are approved by the Department would be adjusted annually consistent with a price-cap formula. The components of the price-cap formula and the results of the Company's productivity study are discussed in detail in the testimony of Dr. Kaufmann.

Q. Has the Company's experience under the previous PBR Plan had an effect on the structure of the Company's proposal in this proceeding?

A. Yes. Although the Company finds itself in the position of needing base-rate relief in this proceeding, the Company's request represents its first base-rate request since 1996. The seven-year period between rate cases is significant in light of the fact that the Company's system is one of the oldest in the U.S. and the capital investment required to maintain the system and to provide safe, reliable quality service to customers is substantial. In the past, these factors led the Company to seek base-rate increases in two to three year time spans. From today's perspective, the Company has avoided a base-rate increase for a relatively prolonged period as a result of two primary factors: (1) the implementation of a PBR plan in 1996 that, over the five-year term of the plan, provided the Company with a measure of additional revenue in consideration of inflationary cost increases; and (2) the Company's success in implementing cost-containment and revenue-enhancement initiatives, which mitigated the impact of system-reliability capital investments and inflationary cost increases not covered by the PBR adjustment.

Still, the Company's business remains rooted in the installation and replacement of gas distribution mains and services, which is heavily dependent upon labor and capital investment, the costs of which typically increase at a rate that is well above inflation. Although the price-cap formula allowed for annual adjustments to rates, only a portion of the cost increases caused by price inflation were recovered through those adjustments. Similarly, the Company's aggressive cost-containment and revenue-enhancement initiatives have worked to mitigate, but not to eliminate, the effect of inflation on total operating and maintenance ("O&M") costs. As a result, there are two main factors that are driving the revenue deficiency from an overall perspective: inflation in basic O&M expenses and increased investment levels in the distribution-system infrastructure for safety and reliability purposes.

In specific terms, approximately one-half of the revenue deficiency is resulting from increases in the cost of employee wages and benefits. In fact, wages and salaries constitute upwards of 49 percent of the Company's annual O&M expenses, and total compensation constitutes about 66 percent, which means that the Company's overall expense level is substantially affected by wage increases that are typically greater than the rate of inflation. The second major factor underlying the revenue deficiency is the Company's investment in distribution infrastructure for safety and reliability purposes. From 1996 through 2002, the Company's annual investment in non-revenue producing mains and services increased from approximately $32.2 million in 1996 to $53.6 million in 2002. In total, for the six-year period 1996 through 2002, the Company invested approximately $270 million in replacement mains and services to enhance system reliability.

The Department's stated intent in pursuing PBR plans has been to provide utilities with the incentive and opportunity to aggressively pursue cost-containment measures. From an overall perspective, the Company has accomplished these objectives through the aggressive implementation of cost-containment and revenue enhancement measures over the past seven years, which have enabled the Company to avoid more frequent base-rate proceedings. At the same time, customers have received rate decreases in real terms and will benefit from the significant long-term investments the Company has made in its system for safety, reliability and service-quality purposes.

Theoretically, if the PBR Plan were perfectly structured, annual base rate adjustments would, over time, allow the Company to recover inflationary increases in O&M expenses and system-replacement activities, while maintaining a strong incentive to minimize costs to the maximum extent possible. The fact that the Company now has a substantial revenue deficiency tends to indicate that the price-cap formula established in D.P.U. 96-50 did not adequately account for the cost increases facing the Company and may have overstated both the productivity differential between the industry and the overall economy and the Company's ability to "stretch" its own productivity growth beyond the industry's productivity norms.

In this case, the Company is proposing to maintain the basic structure of the PBR Plan adopted by the Department in D.T.E. 96-50. However, the Company is proposing modifications to the price-cap formula based on Dr. Kaufmann's analysis of the productivity of the Northeast gas distribution industry and of the Company. Based on his detailed analysis and study, the Company is proposing a price-cap formula that recognizes the cost drivers and productivity potential attendant to the Company's business during the period of the new PBR Plan.

Q. Is the Company proposing a Consumer Dividend as a component of the price-cap formula?

A. The Department has previously recognized that the Consumer Dividend is intended to reflect "future" productivity gains expected from a regulated company operating on a going forward basis under a PBR Plan rather than under a traditional cost of service framework. The Department has also recognized that little information exists to quantify the efficiency improvements that "should" result as regulated gas utilities move from cost-of-service to PBR regulation. Nevertheless, in accordance with the underlying theory that a PBR framework provides a utility with the incentive to achieve efficiency gains that should be shared with customers during the term of the PBR plan, the Company is proposing a Consumer Dividend of 0.15 percent. Although this is lower than the 0.5 percent set by the Department in D.P.U. 96-50-C, it is consistent with the theory of PBR and recognizes that productivity gains during the first PBR term are likely to be greater than those in successive terms. I believe that a Consumer

Dividend of 0.15 percent is consistent with and supported by the analysis presented in Dr. Kaufmann's testimony.

As discussed in the testimony of Dr. Kaufmann, a statistical analysis shows that, as a result of the PBR Plan, the Company's costs declined by 0.30 percent on average during the PBR period of 1997-2000. Since 1997, the Company implemented a number of efficiency improvements that cannot be repeated in the second term of the PBR. For example, the Company completed a comprehensive reorganization of its operations as a result of the QUEST reengineering project. Moreover, in 2000, the Company became part of the KeySpan organization. As described above, the establishment of the Service Company achieves a high level of efficiency since employees collectively work for the consolidated operations, with costs fairly and appropriately assigned pursuant to SEC supervision. As a result of these initiatives, the Company's organization has already been streamlined in a manner that cannot be duplicated.

The cost savings associated with these reductions and other synergies resulting from the KeySpan merger are captured in the test year O&M expense levels. As a result, it will not be possible for the Company to achieve overall cost reductions as great as those achieved during the first PBR term. Therefore, the Company is offering to establish a Consumer Dividend of 0.15 percent in recognition of the theory that increased incentives are inherent in the PBR framework.

Q. Is the Company proposing a change to the Exogenous Factor?

A. No. The Company is proposing to maintain the Exogenous Factor established in D.P.U. 96-50. Under this structure, the Company would be eligible to adjust revenues to account for changes in tax laws, accounting principles, and regulatory, judicial or legislative actions uniquely affecting the local gas distribution industry. In addition, the Company would have the opportunity to propose exogenous changes to the Department in circumstances where it can be demonstrated that the factor driving the cost change is beyond the Company's control and that the cost change is not reflected in the Gross Domestic Product – Price Index. Lastly, individual exogenous costs would have to exceed $500,000 in a particular year in order for the Company to request recovery.

Q. Is the Company proposing a change to the Earnings Sharing mechanism?

A. No. The Company is proposing to maintain the earnings-sharing mechanism established in D.P.U. 96-50. Under this structure, a bandwidth of 400 basis points would be established around the Company's authorized return on common equity of 12.18 percent. If the Company's actual year-end return on common equity is below 8.18 percent, shareholders and ratepayers will share the loss 75 percent and 25 percent respectively. To the extent that the Company experiences a return on common equity above 16.18 percent, the shareholders and ratepayers will share the gain 75 percent and 25 percent, respectively.

Q. What is the Company proposing for the term of the PBR Plan?

A. The term of the PBR Plan would commence on November 1, 2003, coincident with the effective date of the cast-off rates resulting from this proceeding. The initial term of the PBR Plan would continue through October 31, 2008, with five annual compliance filings establishing rates for effect on November 1 of each compliance year beginning November 1, 2004, and with the last rate adjustment taking effect on November 1, 2008. Under the Company's proposal, the PBR Plan could be extended on a year-to-year basis beyond the initial five-year term (the "Extended Term") without further action by the Department. Specifically, the Company proposes to notify the Department each year, beginning June 1, 2009, of its intention to submit a compliance filing on September 15 to extend the term of the PBR plan by an additional year. Unless a base-rate investigation by the Department is initiated (1) by the Department on its own motion; (2) the Attorney General or other entitled persons under G.L. c. 164, § 93; or (3) the Company under G.L. c. 164, § 94, the PBR Plan would extend by operation of the Department's approval of the Extended Term compliance filing.

Q. Is the Company proposing to maintain the pricing flexibility allowed under the first term of the PBR Plan.

A. Yes. In D.P.U. 96-50, the Department allowed the Company to allocate the price cap increase or decrease within a class at its discretion, as long as each rate component increases by no more than the rate of inflation.

V. OTHER PROPOSALS IN THIS PROCEEDING

Reconciliation Mechanism for Pension Costs

Q. What is the Company proposing in this proceeding in terms of a reconciliation mechanism for pension expense?

A. In this proceeding, the Company is proposing to establish a Pension/PBOP Reconciliation Adjustment Clause factor to provide for the recovery of costs associated with the Company's obligation to provide its employees with pension benefits and post-retirement benefits other than pensions ("PBOP"). The proposal follows from the accounting treatment approved by the Department on January 28, 2003 in Boston Gas Company, D.T.E. 03-1. The Pension/PBOP Reconciliation Adjustment Clause tariff is provided as Exhibit KEDNE/JFB-2.

In accordance with that request, the Company's proposed reconciliation mechanism (1) would allow the Company to recover pension costs incurred in providing service to customers, and (2) would ensure that customers pay no more or less than the amounts needed to fund the Company's obligation to employees. In addition, the mechanism is designed to minimize distortions in the Company's financial reports that occur as a result of extreme volatility in pension contributions and expenses, which are caused by events external to the Company and are unrelated to the Company's operating results. This volatility has become particularly acute in recent years because of the decline in the value of pension fund assets resulting from circumstances existing in the financial markets. The financial-reporting distortions are amplified by the fact that there are significant differences in the purpose and operation of the rules governing cash contributions that are required annually to fund the plan, and the accounting treatment prescribed by the Financial Accounting Standards Board ("FASB") to calculate and report pension expense on the Company's books. Because of these circumstances, it has become imperative that the Department explore an alternative ratemaking approach to provide for the recovery in rates of the Company's pension obligation.

Q. What are the FASB standards governing the accounting of pension and PBOP expense?

A. The accounting requirements for pension expense are set forth in Financial Accounting Standard No. 87 ("FAS 87") ("Employers' Accounting for Pensions"). The accounting requirements for PBOPs are set forth in Financial Accounting Standard No. 106 ("FAS 106") ("Employers' Accounting for Post-Retirement Benefits Other Than Pensions").

Q. Please describe the Company's benefit plans relating to pensions and post-retirement employee benefits other than pensions.

A. Boston Gas employees participate in a defined benefit pension plan that covers approximately 1313 employees and 1578 retirees and their beneficiaries. The pension benefits for Boston Gas salaried employees are based on years of service and relative salaries, while the pension benefits for union employees are based on the years of service and the particular benefits negotiated in collective-bargaining agreements. Effective December 31, 2002, KeySpan merged its qualified pension plans, including those for Boston Gas, creating a consolidated "KeySpan Retirement Plan" (the "Plan"). The Plan includes several benefit formulas that are dependent upon an employee's union affiliation or non-represented status. The Company also maintains a trust, which holds the assets available to fund plan benefits for current and future participants in the Plan.

In addition to pensions, the Company provides PBOP benefits to its retirees, such as health and life insurance benefits. The PBOP plan is contributory for retirees with respect to medical benefits and non-contributory with respect to insurance benefits. To fund health-care benefits under the Company's collective-bargaining agreements the Company maintains a Voluntary Employee Benefit Trusts ("VEBA"), to which it makes cash contributions from time to time. As discussed below, the Company currently maintains a deferred PBOP account to which the Company books the difference between the Company's annual FAS 106 expense and the amount collected through rates to fund its PBOP obligation. In this case, the Company is proposing a reconciliation mechanism for pension costs that is similar to the reconciliation mechanism already established for PBOP expense.

Q. How is the Company's pension benefit obligation determined under FAS 87?

A. In basic terms, the Company's pension obligation is the total amount of funds required to meet the Company's pension commitment to retirees and present employees. Under FAS 87, the Company's pension-benefit obligation to its employees is determined in two ways. First, the projected benefit obligation

("PBO") is the actuarial determination of the present value of pension benefits attributed to current and former employees' service to date, based on their expected future pay levels. The accumulated benefit obligation ("ABO") is similar to the PBO except that it is calculated on the basis of current pay levels.

Q. How does the Company fund its pension plan to meet the projected benefit obligation to employees?

A. The Company funds its pension plan through periodic cash contributions made in accordance with Internal Revenue Service ("IRS") rules governing the tax deductibility of cash contributions to trust funds for qualified pension plans. Each year, under the IRS rules, a tax-deductible maximum and minimum limit is set for cash contributions based on the funding status of the plan, as reflected by the ratio of actual plan assets to the Company's PBO. The calculation of the minimum and maximum contribution amounts is a function of the amount of benefits earned during the year by plan participants and the funded position of the plan as of the beginning of the year. Plan sponsors are required to make cash contributions to the plan each year in an amount that is between this annual minimum and maximum calculation. In some cases, the tax-deductible minimum amount may be zero, which means that a cash contribution is not required. However, since the IRS formula reflects the funded position of the Plan, the tax deductible minimum will not be zero when the Plan is substantially underfunded.

Q. Does the Company record the cash contribution as an expense on its books?

A. No. The amount recorded on the Company's books for pension expense is derived in accordance with the accounting rules set forth in FAS 87. FAS 87 provides specific parameters for the assumptions and factors that are used in calculating both the projected benefit obligation and the projected value of the fund assets. These parameters differ substantially from those encompassed in the IRS rules governing the tax-deductible amount of periodic cash contributions. For example, FAS 87 requires that gains and losses on the investment of plan assets must be amortized over a thirteen-year period, i.e., for accounting purposes gains and losses are "matched" with the working lives of employees covered by the Plan. This requirement has the impact of moderating changes in the annual pension expense reported in the Company's financial statements.

The underlying principles of FAS 87 and FAS 106 are two-fold: (1) differences between accounting assumptions and actual plan experience are delayed and recognized over time; and (2) for financial reporting purposes, trust assets and plan obligations, as well as trust earnings and benefits earned, are netted against each other.

Q. What accounts for the difference between the IRS calculation of tax-deductible cash contributions and the FAS 87 calculation of expense?

A. The most significant difference between the IRS tax-deduction rules and the FASB accounting rules relates to consideration of the funded status of the Plan. The IRS formula is geared to encourage employers to maintain sufficient asset balances in the plan to fund projected benefit obligations. Therefore, the maximum contribution each year is based on the "unfunded current liability," as defined by the IRS, and the maximum contribution for the year is generally equal to the unfunded current liability. Therefore, an increase or decrease in the funded position of the plan is immediately reflected in the current tax-deductible thresholds for cash contributions. Under the FAS 87 accounting rules, however, the changes in plan liabilities and assets are always recognized over time because the rules are designed to match expenses with an employee's working life. This timing difference between the funded amount and the expense amount creates a prepayment (cumulative funding greater than expense) or an accrual (cumulative expense greater than funding) balance on the company's books which can become significant at times depending on the volatility in the value of the pension-plan assets.

Q. What is the funded status of the Company's pension plan?

A. As of December 31, 2002, the funded status of the Company's pension plan was as follows:

Projected Benefit Obligation	$ 179,804,000
Asset Value	$ 150,502,000
Funded Status	($ 29,302,000)

As noted above, the projected benefit obligation is the actuarially determined present value of the total cost of pension benefits attributed to service provided by employees to date. The plan assets reflect the fair value of assets as of December 31, 2002. The funded status shows that, on December 31, 2002, the Plan had a projected benefit obligation that is in excess of the Plan assets.

Q. What factors have affected the funded status of the Company's pension plans?

A. The funded status of the Company's pension plans (the ratio of actual plan assets to the Company's projected benefit obligation) has deteriorated as a result of three successive years of financial market declines and unusually low interest rates. Because of the negative impact of both of these factors, the Company's pension plan is below the level of funding needed to meet the Company's projected benefit obligation. As discussed below, these factors combined with growth in plan liabilities have had a significant impact on the Company's earnings and cash flow in recent years.

Q. What impact have these changes had on the level of the Company's cash contributions to the pension plan in recent years?

A. In the past two years, the Company has had to make sizeable cash contributions to its pension plan. The Company has made contributions of $19 million and $44.5 million in 2001 and 2002, respectively. In contrast, since the Company's last rate proceeding in 1996, the Company has been recovering only approximately $1.7 million annually in rates to cover its pension costs.

Q. How do these amounts compare to the Company's recent FAS 87 expense?

A. Financial market volatility in recent years has caused the Company's annual pension expense to increase rapidly. The Company's pension expense, as determined in accordance with FAS 87, has increased from $1.0 million in 2001 to over $6.0 million in 2002. As indicated in the Company's request to the Department on January 28, 2003 in Boston Gas Company, D.T.E. 03-1, the Company's pension expense for 2003 is estimated to increase to $17.0 million.

Q. Please describe how the Department has treated the Company's pension costs in the past for ratemaking purposes?

A. In the past, the Department's ratemaking policy has varied in recognition of the difficulty associated with determining a representative amount of pension costs to be included in rates because of the high level of volatility in the FAS 87 expense and the disparity between the FAS 87 expense calculation and the cash contributions needed to keep the plan funded. In light of the difficulties associated with identifying the appropriate representative level of costs to be included in rates, the Department has adopted various approaches for utilities in Massachusetts, depending upon the specific facts of the case being decided. Generally, the Department has found that including the average of a number of recent years' tax-deductible cash contributions strikes the best balance of interests between customers and shareholders.

For Boston Gas, the Department has applied various approaches. For example, in Boston Gas Company, D.P.U. 93-60 (1993), the Company proposed to include in rates $2,549,557, which was the actual cash contribution made in the 1992 test year. The Department denied the Company's proposal finding that the cash contribution made in 1992 actually pertained to the 1991 allowed tax-deductible contribution. D.P.U. 93-60, at 235. Accordingly, the Department established rates for the Company in 1993 that made no provision for the recovery of any pension expenses or pension obligations from ratepayers. In D.P.U. 96-50, the Department based the pension costs included in rates on the average of the cash contributions made in the four-year period preceding the rate case (1992-1995, inclusive), plus projected cash contributions in 1996. See, D.P.U. 96-50, at 81-82. Based on this approach, the Department provided for the recovery of $1,125,947 in pension costs through rates. Upon reconsideration in D.P.U. 96-50-C, the Department modified its earlier decision and established pension cost based on the five-year historical average of cash contributions for the years 1991 through 1995, which increased the pension costs recovered in rates by $563,530, for total annual recovery of $1,689,477.

Q. How has the Department's treatment of pension expense differed from PBOPs for Boston Gas?

A. FAS 106, which was issued by FASB in December 1990, required the Company to change its then current accounting method from cash (pay-as-you-go) to the accrual basis effective January 1, 1993. This change created a "transition obligation," which represented the obligation existing as of the adoption of FAS 106 on January 1, 1991, or $89,120,000. In December 1991, the Department approved a request by the Company to: (1) defer recognition of the costs covered by the transition obligation; (2) defer the difference between the annual PBOP cost, as calculated using the accrual method, and the amount included in rates; and (3) allow for future recovery of its accumulated PBOP obligation in a subsequent case. D.P.U. 93-60, at 207-208. Following the Department's order, a regulatory asset totaling $99,125,999 was reflected in the Company's books as of December 31, 1992. Therefore, the Department's order in D.P.U. 93-60 created a reconciling mechanism that allowed the Company on a going forward basis to defer the difference between the actual FAS 106 expense and the amount included in rates.

In D.P.U. 96-50, the Department maintained the reconciling mechanism established for PBOPs in D.P.U. 93-60, in order to allow for the continued write-down of the regulatory asset through the deferral of any difference between the actual FAS 106 expense and the amount being recovered through rates. To set the amount in rates, the Department used a five-year average of the total funding for the years 1997 through 2001, inclusive, or $6,774,709. D.P.U. 96-50, at 85-86.

Q. Is the Company proposing to change the ratemaking treatment of PBOPs?

A. No. As recognized by the Department in D.P.U. 96-50, at 84, it is the Company's policy to reconcile the annual PBOP expense pursuant to the requirements of FAS 106 with the amount allowed in rates. The Company is not proposing to change this mechanism, but in fact, is proposing to extend the operation of that mechanism to pension expense. Also, to eliminate the transition obligation, the Company is proposing to amortize over a 10-year period the balance of the transition obligation on its books at December 31, 2002, which was $44 million. This amortization would be included in the reconciliation adjustment factor as of November 1, 2003. The Company has selected a ten-year amortization because the balance on the books as of December 31, 2002 is a significant amount and a relatively longer amortization period will have less of an impact on customers.

Q. For what reason is the Company proposing to extend the PBOP reconciliation mechanism to pension expense?

A. The Company has an affirmative obligation to fund its pension obligation and it is well-established that a representative level of pension costs is properly includable in rates. In the past two years, the Company has made cash contributions well in excess of the level being recovered in rates in order to address the funding issues created by fluctuations in the capital markets and economic environment. Pension plans represent a long-term financial commitment for the Company, yet pension asset valuations under current funding and accounting rules are highly sensitive to short-term fluctuations in the capital markets and economic environment. This volatility has created significant concern over the funded status of pension plans, especially in relation to the cash contributions needed to fund them, as well as the impact that contributions and expenses have on the Company's balance sheet and earnings reports. The Company's proposal presents a reasonable ratemaking approach to provide for the recovery of pension and PBOP costs that are incurred by the Company in providing service to customers, but will also ensure that customers pay no more or less than is necessary to provide those benefits to employees.

Q. What is the Company's proposal for extending the PBOP mechanism to pension expenses?

A. First, the Company is proposing to establish base rates that include in the cost of service the average of the Company's actual cash contributions for the three year period 2000–2002. In 2001, the Company contributed $19,000,000 to its pension plan, and in the test year, the Company made a cash contribution of $44,460,083. The Company did not make a contribution in 2000, but has included this year in the average. Under this proposal, the average annual cash contribution amount is $21,153,361, of which $18,085,435, would be included in base rates ($17,180,551 for direct employees and $904,884 for Service Company employees), with the remainder being capitalized. Since the actual test-year expense recorded on the Company's books was $6,230,016, an adjustment of $11,855,419 was made to the test-year amount. Therefore, the Company's adjusted test year amount to be included in rates of $18,085,435 would be reconciled annually to the pension expense recorded under FAS 87 with the difference being booked to the pension deferral account for subsequent recovery from or refund to customers.

Q. How would the Company reconcile its pension expense?

A. Similar to PBOP, the Company is proposing to establish a mechanism that over time will reconcile the difference between the total amount of pension expense included in the Company's rates as a result of this proceeding ($18,085,435) and the amount of FAS 87 expense that is booked each calendar year. This difference may be either a positive or negative amount, depending on the amount that the Company is required to book as an expense in any year pursuant to FAS 87 rules. As discussed below, beginning November 1, 2003, and in each subsequent year at the time of the Company's annual PBR filing, the Company would submit an accounting of the amount contained in the pension expense deferral account and establish a pension reconciliation factor that will recover or refund one-third of the balance in the account. This amount will be added (or subtracted) to the reconciliation adjustment factor in place from the prior year. The recovery or refund of deferred pension amounts over a rolling three-year amortization period, will allow the Company to recover these deferrals over time, thereby having the effect of "smoothing" the amount of change in the annual adjustment factor from one year to the next. The resulting effect will benefit customers and will serve the Department's long-established ratemaking goal of rate continuity.

Q. Is the Company proposing to include any other amounts in the annual pension expense reconciliation factor?

A. There are two additional components that the Company is proposing to include in the annual pension reconciliation mechanism: (1) the recovery or refund to customers of carrying charges on the balance in the deferred pension cost account described above; and (2) the recovery of carrying costs on the amount by which the Company has pre-funded its pension obligation.

Q. Please describe the Company's proposal to recover or refund carrying charges on the balance in the deferred pension account subject to reconciliation.

A. The rolling three-year amortization and recovery of deferred pension amounts requires the application of carrying charges to ensure that the Company or its customers are compensated for the time value of the money that has been deferred. The Company is proposing to recover from or refund to customers carrying charges at the tax effected weighted average cost of capital established in this proceeding.

Q. What is the "pre-funded pension obligation" that you referred to above?

A. In circumstances where the Company has made cash contributions in excess of the expense level calculated pursuant to FAS 87, a prepaid asset account is created. This balance of this account would increase over time if the Company continued to make annual contributions to the fund in excess of the annual FAS 87 expense levels, and conversely, would be reduced to the extent that contributions were less than the booked expense. Thus, because of the mismatch between the calculation of IRS tax-deductible contribution amounts and the FAS 87 expense amounts, there is the potential for the Company to be in a position where cash contributions are needed to maintain the funded status, and to be consistent with the IRS minimum contribution amount, but the FAS 87 expense is less than the contribution amount. As a result, a prepaid asset is created on the Company's balance sheet.

As of December 31, 2003, the Company has made cumulative cash contributions to its pension plan in excess of its cumulative FAS 87 pension expense in the amount of $54.6 million. Therefore, the Company has a pre-funded asset balance of $54.6 million.

Q. Please discuss how the Company's customers benefit from the pre-funding of the pension obligation.

A. When a prepaid asset account is created for pension costs, the Company's funds are put aside to meet pension obligations and are not available to the Company for other purposes. Therefore, the pre-funding or prepayment of future pension costs is cash that has been provided from Company funds through borrowings from financial institutions and/or advances from the Company's shareholders. As a result, there is a cost associated with using the Company's capital resources to pre-fund the pension obligation. In addition, a component of the Company's FAS 87 pension expense is the expected return on plan assets. As a result of the Company's advanced funding to the Plan, the return on plan assets is greater, producing lower pension expense and a resulting benefit to customers. Accordingly, the Company is proposing to include carrying charges on this prepaid balance at the tax effected, weighted average cost of capital established in this proceeding.

Q. Did the Company address prepaid pension expense in the lead/lag study?

A. Yes. In D.P.U. 93-60, at 60-61, the Department stated that, in order to include prepayments in rate base, the Company needed to submit a lead-lag study, rather than relying on the 45-day working capital determination. In this case, the Company has conducted a lead-lag study and determined that there is a 182-day lead associated with its pension expense. This 182-day lead represents a benefit to customers since it reduces the Company's working capital requirement. Accordingly, the results of the lead-lag study are consistent with the Company's proposal to recover carrying charges on the prepaid expense in this case.

Q. When would the Company file its annual adjustment factor?

A. Because pension plans require a long-term financial commitment for the Company, the pension/PBOP reconciliation mechanism will operate properly for the Company and its customers only if it is in place for the long term. Therefore, the pension/PBOP reconciliation adjustment is designed to be independent of the PBR Plan and to continue in existence even if the PBR Plan were to expire. The Company's proposed Pension/PBOP Reconciliation Adjustment Clause would become effective on November 1, 2003, with the first calculation included in the compliance filing for the base-rate request in this proceeding. However, for subsequent adjustments, the Company would include the pension/PBOP reconciliation adjustment in the annual PBR Plan compliance filing so that rate changes in any year would be implemented all at once.

The reconciliation adjustment factor would include four components: (1) the 10-year amortization of the remaining PBOP transition obligation; (2) the three-year amortization of the deferred pension and PBOP expense balance;

(3) carrying charges applicable to the deferred pension and PBOP expense balance; and (4) carrying charges on the balance of the amount by which the Company has pre-funded its pension expense. These four components would be summed and converted into a unit charge by dividing the total by the number of therms projected to be sold during the upcoming year.

Q. What is the Company requesting that the Department approve in this case?

A. First, the Company requests that the Department establish base rates in this proceeding to recover a representative amount of pension costs in rates, as calculated based on the three-year average (2000—2002) of cash contributions. Second, the Company requests that the Department approve the Pension/PBOP Reconciliation Adjustment Clause tariff proposed in this proceeding. This will enable the Company to file a specific calculation of the adjustment factor as a part of its compliance filing in this case for effect on November 1, 2003, and as a part of its subsequent PBR compliance filings to be submitted to the Department for effect on November 1, 2004, and each November 1st thereafter. The complete calculation and total rate impacts will be demonstrated in those filings based on data for the period ending December 31 of the prior year.

Weather Normalization Clause

Q. Would you please provide an overview of the Company's proposal for a weather-normalization adjustment.

A. Yes. The Company is proposing a Weather Normalization Clause ("WNC") to mitigate the effect of weather on customer bills. The operation of the WNC is discussed in the testimony of Mr. Silvestrini. The Company is making this proposal because weather variations have a direct effect on customer consumption and resultant bills. In particular, when the weather is colder than normal, customers face a "double burden" since their bills are rising due to increased consumption, and they are likely to also experience rising commodity costs. Although lower throughput during warmer-than-normal weather can offset these cost increases over time, it does not make up for the hardships customers experience in the colder periods Over the past three years, customers have become increasingly concerned with the volatility in their bills resulting from the unusual cold and fluctuating commodity costs. Therefore, the Company views the WNC as a way to improve customer satisfaction.

Q. Is the Company's objective in making this proposal to stabilize its distribution revenues?

A. The Company is not making this proposal to stabilize its revenues. Although weather variability has a direct effect on the Company's revenues, the Company has the option of entering into a financial arrangement in the marketplace to mitigate that effect. For example, during the test year, the Company entered into a financial arrangement that in basic terms operates as follows: when the weather is colder than normal (on a defined degree day basis) the Company pays out to its financial partner, and when the weather is warmer than normal (on a degree day basis), the financial partner pays out. For example, in the 2002-03 heating season, the Company paid a total of $15 million to its financial partner as a result of the colder-than-normal weather in the winter months of 2003.

Accordingly, the Company's objective in making this proposal is not to stabilize revenues for the Company, but rather to stabilize the delivery component of customer bills for customers and increase customer satisfaction. Customers do not generally have the option in the marketplace to enter into an arrangement to stabilize the delivery portion of their bills. However, the volatility in gas prices experienced in the past three years and the cold weather of this past winter has had a significant effect on our customers, and therefore, the Company has come under increasing pressure to mitigate the impact of these factors for customers.

Q. How is the WNC designed to operate for customers?

A. The WNC is designed to be objectively determined and symmetrical in terms of the effect of weather on the calculation. The WNC would operate similar to the way that the Company's financial arrangement would work in that the calculation simply compares actual degree days to normal degree days. This means that in warmer-than-normal weather, customers pay a little more, and in colder-than normal weather, customers pay a little less. However, in addition to stabilizing the delivery component of the bill, the Company's proposal provides a benefit to customers in colder-than-normal weather because of the fact that commodity cost increases are also occurring in the colder periods.

As discussed in the testimony of Mr. Silvestrini, the Company has included a 2% monthly deadband in the calculation, which means that no adjustment would occur as long as weather in a particular month deviated from normal within the 2% deadband. The Company is proposing this deadband because the intent of the mechanism is to mitigate the effect of more extreme weather and not to attempt to "match" customer bills to weather. In addition, in the past, the weather-normalization calculation would have had to be put in place in the fall of each year to account for weather in the previous winter period. However, the Company's CRIS system is designed to provide these benefits to customers on a real-time basis, which means that -- when colder (or warmer) weather occurs -- customer bills are adjusted accordingly.

The Company believes that this type of program has value for customers and is seeking the Department's consideration of the proposal for that reason. To the extent that the Company may seek to stabilize revenues, the Company is able to access an arrangement in the marketplace. However, the only way for customers to benefit is for the Company to implement the program on the distribution system.

Non-Firm Margins

Q. Would you please review the Department's current incentive ratemaking policy with respect to interruptible transportation, interruptible sales, capacity release and off-system sales?

A. Yes. The Department's ratemaking treatment of "opportunity" gas sales and transportation-capacity transactions was established in Interruptible Transportation, D.P.U. 93-141-A (1996). Under the framework set forth in that order, the Company is allowed to pursue opportunities to maximize the value of the Company's resource portfolio and to share in the revenues generated by these transactions. In that order, the Department established several categories of transactions, including: interruptible transportation, interruptible sales, capacity release and off-system sales. The Company is allowed to retain 25% of all revenues earned in a given twelve month period May 1 through April 30 above a threshold requirement that is the level of revenues earned in the prior twelve month period ending April 30. Significantly, the threshold is calculated and applied on a category-by-category basis. The remaining 75% of the revenues are flowed back to firm customers.

Q. Why does the Company feel it is necessary to address this issue in this filing?

A. At the time that the Department established its margin-sharing policy, the natural gas marketplace was in the initial stages of development with competition at the wholesale level just taking hold and competition at the retail level in its earliest stages. At the time, local distribution companies in Massachusetts had limited experience with these types of transactions. Therefore, the framework put in place was designed to function based on the circumstances and experience existing at that point in time.

Over time, the Company's experience with this framework has been that there is little value in categorizing these transactions into discrete types. The Company views its gas resources, both on the system and upstream of the system, to be part of an integrated portfolio and has designed its resources to operate in that fashion. In addition, many times, transactions involving a capacity release and/or gas sale may have attributes of one or more categories, and therefore, it is difficult to determine the category in which the transaction falls. For example, since the Department's establishment of the margin-sharing framework in D.P.U. 93-141-A, several LDCs have entered into portfolio management arrangements that involve a set of interrelated transactions including capacity release and off-system sales. These arrangements may involve transactions in more than one category, or a combination of categories. However, it is not practical to track the transactions and to match them up with the defined categories. As a result, the policy established in D.P.U. 93-141-A no longer fits the reality of the marketplace, in terms of both the types of transactions and the incremental revenues available from year to year. Because the margin-sharing formula is no longer consistent with the realities of the marketplace, the structure does not establish appropriate incentives for the Company.

Q. What are some of the problems with the current incentive structure?

A. One example of the mismatch between marketplace realities and the margin-sharing structure is that the current incentive mechanism discourages the use of multi-year transactions. Since 1997, Boston Gas has been a party to a portfolio management arrangement, initially with El Paso Gas Marketing Company and currently with Entergy-Koch Trading. Under each of these arrangements, the Company assigned its portfolio of upstream assets to a third party wholesale marketer. In return for a guaranteed payment to the Company, the portfolio manager is allowed to retain any value derived from the use of the Company's assets, so long as the asset manager meets the firm sendout requirements of the Company. While these arrangements have the potential to provide significant benefits to customers, the Company must devote a fair amount of resources to the RFP process, the negotiations to reach the best deal possible for the benefit of customers, and then the day-to day management of the relationship over the term of the contract, which is vital in ensuring that the Company is maximizing every opportunity within the resource portfolio and maintaining safe and reliable service to customers.

With the experience gained through these asset-management arrangements, it is clear that long-term multiple year arrangements generate the greatest value and therefore, provide the greatest revenue opportunities for the Company and its ratepayers. However, payments tend to be levelized over the contract term. Thus, under the Department's policy, there is little or no opportunity for the Company to earn an incentive after the first year since the first year payment sets the threshold goal for the subsequent year. Such a mechanism does not, therefore, properly align the Company's incentives with the saving opportunities available to ratepayers.

In addition, the "threshold" aspect of the margin-sharing framework does not provide adequate or appropriate incentives to maximize value for customers because it is unrealistic to expect that there are ever-increasing opportunities available to the Company in pursuing value for customers. For example, the establishment of a threshold based on the prior year's activity is not effective in providing an incentive to the Company where revenue opportunities are a function of weather and firm-system demand. Weather and firm-system demand largely determine the amount of resources available to meet firm sendout requirements, and therefore, the opportunities for mitigation through capacity-release, off-system sales or interruptible transactions are largely dictated by changes in weather and system demand from year to year. Thus, if the current year is significantly colder than the prior year, the threshold is unattainable, even if the Company has worked hard to ensure that the maximum level of value has been extracted from the portfolio in that time period. Conversely, if the current year is significantly warmer than the past year, more of the Company's resources are available for mitigation and the threshold is easily reached and exceeded.

Similarly, the Company's opportunities are circumscribed by market circumstances. The value derived in the marketplace in one year, may not be available in another year, despite the fact that the Company has exercised the same level of effort in seeking out mitigation opportunities. In fact, changes in market conditions may require a higher level of innovation and effort by the Company to achieve the value for customers on par with past market opportunities. Lastly, a threshold based on historical performance does not adjust for normal growth, which also tends to reduce the assets available for mitigation in the marketplace.

Q. Does the Company have a proposal for a different incentive mechanism?

A. Yes. The Company is proposing to simplify and rationalize the current mechanism to allow the Company an opportunity to earn an appropriate incentive and ensure that customers receive the maximum possible benefits for the use of its resources, both on-system and off-system. For all of these reasons, the Company is proposing to eliminate the categories and the threshold structure and apply the 25/75 margin-sharing formula to total non-firm margins. This change will better align the incentives available to the Company with the savings opportunities available for the benefit of customers.

Gas Industry Research and Development

Q. Please address the Company's proposal for recovering research and development costs in rates.

A. In 1977, the Gas Research Institute ("GRI"), now known as the Gas Technology Institute ("GTI"), was formed by the interstate gas pipeline and LDC industries in agreement with the Federal Energy Regulatory Commission ("FERC") in order to perform research and development ("R&D") for the gas industry. To that end, R&D costs were included in a FERC-approved interstate pipeline charge to LDCs, which typically passed the charge on to end-use customers. In 1998, FERC, the interstate pipelines and the LDC industry reached agreement to phase out the GTI surcharge of 1.74 cents then being collected in pipeline rates by 2003. In over a dozen states, state regulatory commissions have approved mechanisms to collect an R&D charge through rates to replace the GTI surcharge and maintain funding for these activities. In other states, similar programs are under consideration.

In this proceeding, Mr. Edelstein's testimony addresses the type of R&D initiatives undertaken by GTI for the benefit of gas consumers. Based on the historical success of these R&D programs and the resulting benefits to gas customers, Boston Gas is proposing that the Department create an R&D charge that would restore the level of R&D funding previously supported by Boston Gas customers through pipeline-gas purchases in the past. Because customers previously funded the R&D based on a surcharge per Mcf of pipeline gas, the

Company proposes to maintain that structure and collect 1.74 cents per Mcf only on pipeline gas and not on liquefied natural gas ("LNG" sales). As a result, the actual charge would be based on the ratio of pipeline gas to total gas purchased by the Company and would actually be less than that 1.74 per Mcf of consumed gas. The Company proposes to recover this charge in the Local Distribution Adjustment Charge ("LDAC").

The LDAC charge would begin January 2004, when the current GTI surcharge is scheduled to expire. Based on test year weather-normalized load, annual R&D revenues would be approximately $1.4 million.

Q. **How will the Company supervise the use of the R&D funds?**

KeySpan has an internal R&D unit that supervises the expenditures of R&D program funds using the funding generated by the New York LDCs. KeySpan uses the funds to support various R&D efforts, including the GTI program, Pipeline Research International, the U.S. Department of Energy, and Battelle Laboratories. KeySpan would use the same approach in applying the funding provided by Boston Gas customers, which is to use the funds in a way that maximizes value for Boston Gas customers on a cost-effective basis.

Q. **What types of R&D programs does the Company intend on sponsoring?**

A. The programs will all be of benefit to the Company's sales and distribution customers. These consumer-interest R&D projects would address:

- Enhanced distribution system integrity, reliability, and deliverability.

- Enhanced distribution system security.
- Lower distribution system O&M costs.
- Enhanced health and safety (distribution system, gas consumer, and general public).
- Enhanced distribution system environmental quality.
- Increased-efficiency, lower-emissions end-use equipment.

Q. Is the Company proposing specific programs at this time?

A. No. At this time, the Company is requesting that the Department approve the restoration of the level of funding that was in place in 1998 of 1.74 cents per Mcf and approve using the LDAC for that purpose. The Company would then file a program proposal with the Department by December 1 of this year, and by October 1 of each subsequent year. The R&D program proposal would outline the Company's annual plan for funding of R&D initiatives within a program budget that is based on anticipated collections. The LDAC charge would begin on January 1, 2004, when the current GTI surcharge is scheduled to expire.

Q. Does this complete your testimony?

A. Yes. It does.